BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

In the matter of the investigation of the continued reasonableness of current size limitations for PURPA QF published rate eligibility (i.e. 1MW) and restrictions on contract length (i.e., 5 years).	) CASE NO. GNR-E-02-1)) Direct Testimony and Exhibits of) Mark T. Widmer on Behalf of) PacifiCorp

July, 2002

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PACIFICORP

July, 2002

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My Name is Mark Widmer, my business address is 825 N.E. Multnomah, Suite 800, Portland, Oregon 97232, and my present position is Manager, Regulation.

Qualifications

Q. Briefly describe your education and business experience.

A. I received an undergraduate degree in Business Administration from Oregon State University. I have worked for the Company since 1980 and have held various positions in the Power Supply and Regulatory areas. I was promoted to my present position in March 2001.

Q. Please describe your current duties.

A. I am responsible for the coordination and preparation of net power cost and related analysis used in retail price filings. In addition, I represent the Company on power resource and other various issues with intervenor and regulatory groups associated with the six state regulatory Commissions to whose jurisdictions we are subject. I am responsible for monitoring and when necessary filing avoided cost prices for the Company.

Purpose of Testimony

Q. What is the purpose of your testimony?

My testimony is in response to Idaho Commission Order No. 29069, on petitions for reconsideration and motions for stay in this case, which set a hearing schedule for the review of the reasonableness of the currently approved input variables for the avoided cost calculation. I will present the Company's proposed surrogate avoided resource (SAR) input updates and updated avoided costs that the Company requests the Commission to adopt.

Avoided Cost Update

Q. Are the Company's current published avoided cost rates representative of the Company's current avoided costs?

A. No. Exhibit 301 demonstrates that the Company's current published avoided cost rates, which are based on outdated inputs, significantly overstate the Company's avoided costs, when updated inputs are used. This overstatement exposes the Company and its customers to the possibility of paying significantly more for QF power than is reasonable. Exhibit 301 shows that payments for a 10 MW QF with a twenty-year contract at the current published avoided cost rates would be 93% or $52.5 million higher than rates based on the Company's updated inputs.

Q. Which variables does the Company propose to update so that avoided costs are representative of the Company's current costs?

A. I believe most of the inputs used in the current avoided cost calculation should be updated, because they are very stale. The only variables that are still reasonable and do not need to be updated are the SAR plant life, and capacity factor.

Q. Are the proposed changes based on the Company's last completed Integrated Resource Plan (IRP), RAMPP-6?

A. No. Just as the inputs used in the current avoided cost calculation are stale, RAMPP-6 inputs are stale. RAMPP-6 information is no longer representative of the Company's current situation, because RAMPP-6 is based on May 2000 information. The proposed changes are based on the most recent information available to the Company. In my following testimony, I will discuss the proposed input changes and the Company's proposed avoided cost rates.

SAR Model Inputs

First Deficit Year

Q. What is the Company's updated first deficit year?

A. As shown on Exhibit 302, the Company's updated first deficit year is 2008. The Company moved from a previously forecast energy deficit in 1999 to an energy deficit beginning in 2008 for numerous reasons. Actual loads are significantly less than forecast loads assumed in the 1994 study from which the current avoided cost rates are based, partially due to the sale of the Company's Montana distribution property. Long-term firm wholesale sale volumes will be significantly lower than previously expected. For example, the Company's WAPA II and Block A of the WAPA I contracts were suspended by mutual consent of the parties, December 2000. Long-term firm wholesale purchases will be higher than previously expected. For example, the Company extended the Grant County portion of the Mid Columbia power purchase contracts and signed a new contract with TransAlta for replacement power for the sale of the Centralia generation unit. Also on the thermal side, the Company built 120 MW of simple cycle combustion turbines (SCCT) at its Gadsby plant and leased 200 MW of

SCCT in West Valley Utah. Further, the Company has improved the efficiency and capacity of some thermal generation plants through turbine upgrades.

SAR CCCT

Q. Does the Company propose to update the SAR CCCT in this case?

A. Yes. In Order No. 25882, the Commission adopted the General Electric (GE) Frame 7FA 230 MW gas CCCT identified by the Northwest Power Planning Council as the generic SAR CCCT. In this case, the Company proposes that the SAR CCCT be a GE 7FA 2x1 CCCT. The 7FA 2x1 CCCT is a 490 MW nameplate plant with two turbines, one heat recovery system and with a heat rate of 7,074 Btu/kWh. The Commission-approved version has a single turbine and one heat recovery system.

Q. Please explain why the assumed SAR CCCT unit should be revised?

A. The GE 7FA 2x1, which did not exist at the time of the Commission's prior determination, reflects current technology and efficiencies, and is more representative of a CCCT plant the Company would be likely to build. This plant is identical to the Klamath Cogeneration Project, built in Klamath Falls by PPM, the Company's unregulated power marketing affiliate.

Two turbines tied to a single heat recovery system produce considerable economies of scale compared to the currently assumed SAR plant. The 7FA 2x1 also has a lower capital cost, lower fixed and variable O&M costs and a lower heat rate. As shown in the table below, two 7FA units would cost $369 million, while a single 7FA 2x1 would cost $294 million and would have 20 additional

MW of capacity. That represents a savings of $76 million in capital costs alone, not to mention the additional capacity and ongoing savings in O&M and fuel.

	Commission Adopted 7FA 1x1 CCCT	Company Proposed 7FA 2x1 CCCT
Size	235 MW	490 MW
Capital Costs $/kW	$ 786	$ 600
Fixed O & M $/kW per year	$ 11.29	$ 6.65
Variable O & M $/MWH	$ 1.67	$ 1.53
Heat Rate Btu/kWh	7,235	7,074
*2002 Dollars at ISO conditions, includes AFUDC		

Q. What is the source of the cost estimates mentioned above?

A. The Company's Generation Engineering group prepared a detailed study in conjunction with Black & Veatch, a nationally known engineering company. The costs were developed for use in the Company's current IRP process as well as ongoing internal planning purposes.

Q. Please explain how capital costs are expected to escalate in the near future?

A. Turbine costs are currently relatively low because of an oversupply of gas turbines in the market. Due to the oversupply, capital costs are expected to decline 5% by 2004, then are expected to firm up starting in 2005 and escalate at 2% per year through 2007.

Q. What is the Company's recommendation for the SAR escalation rate in this case?

A. Based on the Company's study, capital costs are expected to be 2.8% higher in 2008 than they are today. This equates to an annual escalation rate of .47%. As such, the Company proposes a .47% escalation rate through 2007 and a 2.5% general inflation rate over the remainder of the 20-year term for QF contracts.

SAR O&M Costs

Q. What are the Company's proposed O&M cost inputs for a generic 7FA 2x1 CCCT?

A. Those costs are shown in the table below. The Commission recognized the importance of consistency between SAR inputs in Order 25822 when it stated:

> Because we have adopted the gas CCCT identified by the Northwest Power Planning Council as the SAR, we find that it is consistent to also adopt the generic variables utilized by the Council.

Those generic variables are capital cost, capacity factor, fixed and variable O&M, fuel cost and heat rate.

Q. How were the Company's proposed O&M costs developed?

A. The O&M costs, along with other operating variables were included as part of the Generation Engineering study I discussed earlier in my testimony.

Q. Should the proposed capital and O&M costs shown above be adjusted for expected site conditions?

A. Yes. As shown in the table below, the proposed capital and O&M costs were adjusted for the effect of altitude and temperature on plant nameplate capacity. Plant costs are typically quoted at ISO (International Organization for Standardization) conditions, a standardized altitude, air temperature and humidity. The SAR unit is assumed to be constructed in northeastern Oregon, which has a higher altitude and summer ambient air temperature than the ISO conditions.

Therefore, summer capacity is expected to be 5% less than it would be under ISO conditions, which results in a 5.2% increase in capital cost and O&M cost per kW. The Company's proposed plant cost is $631.58 per KW.

Plant Cost Adjustment

	Plant Cost - 7FA 2x1		
	ISO $	Site Adj	Proposed $
Capital Cost	$ 600.00	95%	$ 631.58
Fixed O&M	$ 6.65	95%	$ 7.00
Variable O&M	$ 1.53	95%	$ 1.61

Plant costs adjusted for altitude & temperature.

SAR O&M Escalation Rate

Q. How does the 3.6% inflation rate input for the current avoided cost rates compare to the Company's proposed inflation rate?

A. The 3.6% rate is significantly higher than the 2.5% inflation rate input that the Company proposes for its updated avoided cost calculation. Over the last 8 years inflation has eased and stabilized between 2% to 2.5% per year.

The 2.5% inflation rate is also being used in the Company's Official Market Price Projections, and the current IRP process, and is a reasonable rate for purposes of setting administratively determined avoided cost rates.

Tilting Rate

Q. Please explain what the "Tilting" Rate (%) is and where it is used?

A. The "Tilting" rate is used to adjust the levelized capital cost payment stream. A levelized payment stream is flat over the duration of the payment stream, very much like a mortgage payment is levelized and flat over the life of the mortgage. A tilted payment stream starts below the levelized payment stream and escalates at the rate of inflation. The net present value of the levelized and tilted payment streams is identical.

Q. What "Tilting" rate input does the Company recommend for the updated avoided cost calculation?

A. Consistent with prior Commission practice, the Company proposes that the inflation rate be used as the tilting rate. The Company therefore proposes a 2.5% tilting rate.

Cost of Capital

Q. What capital cost structure did the Commission adopt in Order 25882?

A. The Commission adopted the Company's capital structure as used in the then most current RAMPP study, RAMPP-3.

Q. Should the Commission adopt a similar approach in this filing?

A. No. The most current RAMPP document is RAMPP-6. The capital structure in RAMPP-6 was developed in January of 2000, and is now two and a half years old.

Q. What is the Company's recommended cost of capital input for the Company's updated avoided cost calculation?

A. The Company recommends that the 8.87% cost of capital approved by the Utah Commission in Case 01-035-01, be used as the cost of capital input for the Company's updated avoided cost calculation. The capital components are shown in the table below.

Capital Component	Percent	Cost	Weighted Cost
Cost of Long-Term Debt	49.2%	6.99%	3.44%
Cost of Preferred Stock	3.2%	6.18%	.20%
Cost of Equity	47.6%	11.00%	5.23%
Total	100.0%		8.87%

Capital Carrying Charge

Q. Would you explain the capital carrying charge calculation?

A. The capital carrying charge is a calculation of the levelized cost of owning an asset. Major inputs into the calculation are: utility capital structure, book and tax life, tax rates, and administration and general (A&G) expense.

Q. Please identify the major assumptions for the capital carrying charge calculation.

A. The major assumptions are shown below:

Weighted Cost of Capital	8.87%
Book Life	30 years straight line
Tax Life	20 years Modified ACRS
Property Tax Rate	1.20%
A&G Expense	1.47%
A&G Escalation Rate	2.5%
State Income Tax	4.68%
Federal Income Tax	35%

Q. What is the source for each of these inputs?

A. Tax and A&G expense rates are system-wide factors developed from the Company's 2001 FERC Form 1. Cost of capital and inflation rates are discussed in my testimony above.

Q. What is the Company's proposed capital carrying charge?

A. Based on the assumptions I discussed above the Company's proposed capital carrying charge is 13.26%

Q. Does the Company recommend changing either the plant life or the expected SAR capacity factor inputs for the Company's updated avoided cost calculation?

A. No. The expected plant life of a CCCT has not changed and should continue to be 30 years. The 92% capacity factor adopted by the Commission in Order 25822 continues to be a reasonable estimate for a base loaded CCCT.

Surplus Energy Cost

Q. Does the Company believe the Surplus Energy Cost should be updated?

A. Yes. The region has recently gone through an energy supply crisis and is near resource balance. Hence, market prices today are now higher than the currently-approved Surplus Energy Cost because the current cost was set during a period of region-wide resource surplus.

Q. What is the Company's surplus energy cost recommendation?

A. The Company recommends a 2002 Surplus Energy Cost of $33.54 per MWh. The price is the average of the California Oregon Border (COB), Palo Verde and

Mid Columbia prices from the Company's June 2002 Official Market Price Projections for the period July 2002 through December 2002.

Q. What is the Company's Official Market Price projection?

A. The Official Market Price projections are the Company's official set of projected market prices that are used in all net power cost and related analyses, including avoided cost filings where applicable and the Company's IRP process.

Q. Please explain how the Company's Official Market Price projections are developed.

A. The Official Market Price projections are developed by the Company's Commercial and Trading Department and are a blend of forward market prices and market prices forecast by the Company's market price clearing model, Midas. Forward market prices are solely used through May 2005, the remainder of 2005 is weighted 75% forward market prices / 25% Midas, the first half of 2006 is weighted 50-50 between forward market prices and Midas, and the last half of 2006 is weighted 25% forward market prices / 75% Midas. Starting in 2007 only Midas results are used.

Q. Please explain how forward market prices are developed.

A. Forward market prices are averages derived from actual market transactions and from independent third party broker quotes.

Q. Please explain how the Midas market price clearing model works.

A. Midas models loads, resources and a simplified transmission representation of the entire WECC region. The model calculates market prices to be the variable cost of the last unit running to meet the last unit of demand in each of the sixteen WECC load centers. Midas also simulates the addition of new generation resources in response to market prices. New resources are automatically added to the supply of resources when market prices are sufficient to recover costs, including capital recovery. Midas uses the Company's most recent projected CCCT capital and O&M costs.

Surplus Escalation Rate

Q. What is the Company's proposed surplus escalation rate?

A. The Company proposes a surplus escalation rate of 4.8% through 2007.

Q. Please explain how the surplus escalation rate was developed?

A. As shown in the table below, the proposed annual escalation rate is the rate necessary to escalate the Company's 2002 Official Market Price projection of $33.54 per MWh to the 2007 Official Market Price Projection of $42.40 per MWh. The Company's approach is conservative because it assumes that the rate of escalation occurs ratably over the surplus period, when in fact the highest growth is expected to occur during the last two years of the surplus period.

Wholesale Prices (1)

	COB	PV	Mid C	Average	Esc
2002	35.09	32.86	32.66	33.54	0.0%
2003	35.44	33.09	33.67	34.07	1.6%
2004	35.07	32.35	34.37	33.93	0.6%
2005	36.76	32.35	34.99	34.70	1.1%
2006	41.07	33.64	39.28	38.00	3.2%
2007	45.60	37.30	44.30	42.40	4.8%

Source: Fundamentals Group Official Price Forecast
(1) Flat Prices 7 x 24 Cyclic Growth (Page 2)

Natural Gas Prices

Q. Do you believe that the gas price and gas escalation inputs for the current avoided costs are representative of the current market?

A. No, and the non-representative nature of these inputs was noted in the Supplemental Answer of the Commission Staff in this case, where the Commission Staff stated:

> Under the current avoided cost methodology, fuel costs represent a substantial component of the avoided cost rate. In establishing the fuel component of the rate for non-fueled projects, a starting fuel price is computed that reflects an average of the natural gas prices during the previous calendar year at Sumas, Washington. That starting fuel price is then escalated at a six percent rate over the life of the QF contract. Actual fuel prices in previous years, and forecasted prices in subsequent years, have no bearing on the computation of the avoided cost rate. The effect of this computation is that a contract signed in a year when gas prices are high enjoys the benefit of that high gas price for the duration of the contract. . . . .
>
> . . . .
>
> At the present time, the starting fuel price subject to 6% escalation over the life of the contracts signed or requested this year is $4.82 per MMBtu. This price will increase to $5.23 in July if approved by the Commission. Under any other gas price methodology such as historical averages, historical trend lines or future market projections, the resulting avoided costs would be significantly below that using existing methodology. For example, the non-fueled levelized rate in 2002 for a five-year contract using a starting gas price of $5.23 per MMBtu is $56.42 per MWh for Idaho Power. Using an historical trendline and regression equation (Attachment 2) results in a starting gas price of $3.20 per MMBtu and a 5 year levelized rate of 43.34 per MWh.
>
> The difference is magnified by the Commission's recent decision to increase contract lengths from five years to twenty years. The twenty year levelized rate under the existing methodology is $76.11 per MWh, compared to $57.87 per MWh using a trendline technique to establish a starting gas price. Using other gas price methodologies results in even lower levelized avoided cost rates.

Staff's comments are very illustrative of why the Company and other Idaho utilities face excessive QF cost exposure from current avoided cost rates, and why it is imperative that the Commission adopt updated avoided cost rates for Idaho utilities.

Q. What is the Company's recommendation for a 2002 current year fuel cost and adjustable portion?

A. The Company recommends a current year fuel cost of $27.94 per MWh. As shown below, the proposed current year fuel cost was developed from a June 2002 through December 2002 gas price forecast, plus 2% for shrinkage and $.40 per MMBtu for transportation, and a 7,074 heat rate for the Company's proposed SAR CCCT. The shrinkage and transportation assumptions were taken from the Company's Official Market Price Projections. Shrinkage is natural gas used by the pipeline Company to pressurize and pump the natural gas. The transportation charge is the estimated cost to deliver gas to a CCCT plant located in northeastern Oregon. The gas price forecast, which is also used in the Company's Official Market Price projection, was obtained from PIRA, a well-known energy

Mills/kWh Calculation

Year	Sumas $/MMBTU
6/1/02	3.13
7/1/02	3.19
8/1/02	3.23
9/1/02	3.23
10/1/02	3.23
11/1/02	4.07
12/1/02	4.27
Average 2002 Prices	3.48
Shrinkage (Losses)	2.0%
Adjusted Price	3.55
Transportation	0.40
Delivered Fuel Cost	3.95
7FA 2x1 CCCT Heat Rate	7,074
Generation Cost In Mills/kWh	27.94

consulting and forecasting group in New York City.

Q. How does the Company's proposed fuel cost compare to the fuel cost that, prior to Order 29069, was scheduled to go into effect July 1, 2002?

A. The fuel cost that was scheduled to go into effect July 1, 2002 is $38.44 per MWh. That is $10.50 per MWh or 38% higher than the level justified by current gas prices during the first year, and the disparity only grows over the twenty-year term that is available for QF contracts.

Natural Gas Escalation Rate

Q. What is the Company's proposed natural gas escalation rate?

A. Based on the Company's Official Market Price projections, the Company proposes a 1.97% natural gas escalation rate per year. The rate is developed from the $5.04 per MMBtu in year 2021 (the twentieth year of the study) and the $3.48 per MMBtu forecast gas price for the last half of 2002. The gas escalation rate of 1.97% per year is the rate necessary to escalate $3.48 per MMBtu to $5.04 per MMBtu over that period.

Proposed Avoided Costs

Q. What are the Company's proposed avoided costs in this case?

A. Exhibit 303 shows the Company's proposed Fueled avoided costs. Exhibit 304 shows the Company's proposed Non-Fueled avoided costs.

Q. Were the proposed avoided costs developed using the Commission approved SAR model?

A. Yes. The proposed avoided costs were developed with the Commission approved SAR model and the proposed inputs I discussed earlier in my testimony.

Q. Do you have any final comments regarding the prices that will be made available to QFs up to 10 MW?

A. Yes. The published rates proposed by the Company, although calculated in accordance with the Commission approved SAR model, still tend to overstate the Company's avoided costs because the rates are based on the costs of a fully dispatchable CCCT which can provide load following, be ramped up and down based on economics and can carry spinning and non-spinning operating reserves. None of these capabilities have historically been available from QFs.

Q. Does this conclude your direct testimony in this case?

A. Yes.

Case No. GNR-E-02-1
Exhibit 301
Witness: Mark T. Widmer

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer

July, 2002

Case No. GNR-E-02-1
Exhibit 301
PacifiCorp
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Exposure due to higher than necessary QF prices

Year	Energy MWH	Paid to QF Customer			
		$/MWH		Total Annual Dollars	
		Current	Propose	Current	Propose
2002	61,320	51.46	33.54	$ 3,155,527	$ 2,056,468
2003	61,320	54.22	35.15	$ 3,324,770	$ 2,155,179
2004	61,320	57.14	36.83	$ 3,503,825	$ 2,258,627
2005	61,320	60.22	38.60	$ 3,692,690	$ 2,367,042
2006	61,320	63.47	40.45	$ 3,891,980	$ 2,480,660
2007	61,320	66.90	42.40	$ 4,102,308	$ 2,599,731
2008	61,320	70.53	43.34	$ 4,324,900	$ 2,657,802
2009	61,320	74.36	44.26	$ 4,559,755	$ 2,714,039
2010	61,320	78.41	45.20	$ 4,808,101	$ 2,771,481
2011	61,320	82.69	46.15	$ 5,070,551	$ 2,830,154
2012	61,320	87.21	47.13	$ 5,347,717	$ 2,890,084
2013	61,320	91.98	48.13	$ 5,640,214	$ 2,951,300
2014	61,320	97.03	49.15	$ 5,949,880	$ 3,013,829
2015	61,320	102.36	50.19	$ 6,276,715	$ 3,077,699
2016	61,320	107.99	51.25	$ 6,621,947	$ 3,142,940
2017	61,320	113.94	52.34	$ 6,986,801	$ 3,209,581
2018	61,320	120.23	53.45	$ 7,372,504	$ 3,277,654
2019	61,320	126.88	54.59	$ 7,780,282	$ 3,347,188
2020	61,320	133.91	55.74	$ 8,211,361	$ 3,418,216
2021	61,320	141.35	56.93	$ 8,667,582	$ 3,490,771
		Total Payments		$109,289,410	$56,710,445
		Exposure [Current - Proposed Cost]			$52,578,964
		Ratio [Current to Proposed]			1.93

Assuming 10 MW, 70% Capacity Factor and 20 Year Non-Fueled Contract.

Case No. GNR-E-02-1
Exhibit 302
Witness: Mark T. Widmer

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer

July, 2002

Exhibit 2

PacifiCorp
Loads and Resources
Average Megawatts

	2002	2003	2004	2005	2006	2007	2008
Requirements aMW							
Net System Load	6,149	6,238	6,345	6,504	6,647	6,764	6,917
Long Term Firm Sales	877	812	686	564	513	375	348
Total Requirements aMW	7,026	7,050	7,031	7,068	7,160	7,139	7,264
Resources aMW							
Long Term Firm Purchases	1,111	1,132	1,122	1,123	1,126	918	725
Thermal Generation /1	5,923	5,999	5,999	5,999	5,999	5,999	5,777
Hydro Generation	551	551	551	551	551	551	551
Total Resources aMW	7,585	7,682	7,672	7,674	7,676	7,468	7,053
Balance Surplus/(Deficit)	559	633	641	605	516	329	(212)

/1 Includes maintenance

PacifiCorp
Loads and Resources [Idaho Avoided Cost Study]
Period 2002 - 2010

AVERAGE MEGAWATTS	2002	2003	2004	2005	2006	2007	2008
REQUIREMENTS							
Net System Load	6,149	6,238	6,345	6,504	6,647	6,764	6,917
Long Term Firm Sales							
AEPC	2	2	-	-	-	-	-
Black Hills	50	46	42	42	42	42	42
BPA Flathead	54	54	54	54	40		
BPA Wind	5	5	5	5	5	5	5
CDWR	70	70	70	-	-	-	-
Clark Wafertech	9	-	-	-	-	-	-
Citizens Power	10	-	-	-	-	-	-
COPD (BHP Steel)	3	-	-	-	-	-	-
Deseret Supplemental	38	19	-	-	-	-	-
Flathead	16	16	16	16	12	-	-
Hurricane Sale	1	1	1	1	1	0	-
LADWP (IPP Layoff)	62	62	61	62	62	62	61
PSCO	132	132	132	132	132	132	105
Puget Sound	120	100	-	-	-	-	-
SCE	114	114	114	114	86	-	-
Sierra Pac 2	53	53	53	53	53	53	53
SMUD	40	40	40	40	40	40	40
Springfield	26	26	26	26	26	26	26
UMPA	5	5	5	5	-	-	-
UMPA II	15	15	15	15	15	15	15
WAPA D	53	53	53	-	-	-	-
Total Long Term Firm Sales	877	812	686	564	513	375	348
TOTAL REQUIREMENTS	7,026	7,050	7,031	7,068	7,160	7,139	7,264

RESOURCES	2002	2003	2004	2005	2006	2007	2008
Long Term Firm Purchases							
APS Supplemental	4	3	3	3	3	3	3
Avista Summer Capacity	9	9	-	-	-	-	-
BPA So. Idaho Exchange	4	(1)	2	2	2	2	2
Canadian Entitlement CEAEA	(7)	(11)	(12)	(11)	(8)	(8)	(8)
Colockum Exchange	(23)	(13)	-	-	-	-	-
CSPE	9	2	-	-	-	-	-
Deseret G&T Expansion	25	14	-	-	-	-	-
DOPD Settlement	9	9	9	9	9	9	9
Foote Creek I	14	14	14	14	14	14	14
Fort James	43	42	43	43	42	43	43
Gemstate	6	6	6	6	6	6	6
Grant County	10	10	10	10	10	10	10
Hermiston Purchase	220	220	220	220	220	220	220
Hurricane Purchase	0	0	0	0	0	0	0
Idaho Power RSTA Return	(9)	(9)	(9)	(9)	(9)	(9)	(9)
IPP Purchase	62	62	61	62	62	62	61
MagCorp	21	21	21	21	21	21	21
Mid Columbia	219	219	219	219	219	219	219
Misc Purchases East	1	1	1	1	0	-	-
Misc Purchases West	6	6	6	6	6	-	-
PGE Cove	2	2	2	2	2	2	2
QF Biomass	10	10	10	10	10	10	10
QF D.R. Johnson	7	7	7	7	7	-	-
QF Hydro East	9	9	9	9	9	9	9
QF Hydro West	18	18	18	18	18	18	18
QF Sunnyside	44	44	44	44	44	44	44
SF Phosphates	8	-	-	-	-	-	-
Rock River	19	19	19	19	19	19	19
Transalta Purchase	340	388	388	388	388	192	-
Tristate Purchase	32	32	32	32	32	32	32
Total Long Term Firm Purchases	1,111	1,132	1,122	1,123	1,126	918	725

	2002	2003	2004	2005	2006	2007	2008
Thermal Resources							
Blundell	19	19	19	19	19	19	19
Carbon	156	156	156	156	156	156	156
Cholla	339	339	339	339	339	339	339
Colstrip	122	122	122	122	122	122	122
Craig	154	154	154	154	154	154	154
Dave Johnston	654	654	654	654	654	654	654
Gadsby	223	223	223	223	223	223	
Gadsby CT	17	52	52	52	52	52	52
Hayden	66	66	66	66	66	66	66
Hermiston	220	220	220	220	220	220	220
Hunter	948	948	948	948	948	948	948
Huntington	786	786	786	786	786	786	786
Jim Bridger	1,263	1,263	1,263	1,263	1,263	1,263	1,263
Little Mountain	13	13	13	13	13	13	13
Naughton	638	638	638	638	638	638	638
West Valley CT	45	87	87	87	87	87	87
Wyodak	259	259	259	259	259	259	259
Total Thermal Generation	5,923	5,999	5,999	5,999	5,999	5,999	5,777
Hydro Resources							
West Hydro	499	499	499	499	499	499	499
East Hydro	52	52	52	52	52	52	52
Total Hydro Generation	551	551	551	551	551	551	551
TOTAL RESOURCES	7,585	7,682	7,672	7,674	7,676	7,468	7,053
BALANCE Surplus/(Deficit)	559	633	641	605	516	329	(212)

Case No. GNR-E-02-1
Exhibit 303
Witness: Mark T. Widmer

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer

July, 2002

AVOIDED COST CALCULATION MODEL
19-Jul-02
FUELED

DATA TYPE	DATA SOURCE	PCP DATA
FIRST DEFICIT YEAR:	Long Run L&R	2008
SURPLUS ENERGY COST (mil/kWh):	June 2002 Official Forecast	33.54
SURPLUS COST BASE YEAR:	June 2002 Official Forecast	2002
"SAR" PLANT LIFE (YEARS):	No Change	30
"SAR" PLANT COST ($/kW):	June 2002 Official Forecast	$632
BASE YEAR OF "SAR" COST:	June 2002 Official Forecast	2002
"SAR" CAPACITY FACTOR (%):	No Change	92%
UTLTY WT'D COST OF CAPITAL (%):	Oregon Order 01-787	8.620%
RATEPAYER DISCOUNT RATE (%):	Oregon Order 01-787	8.620%
"SAR" FIXED O&M ($/kW):	June 2002 Official Forecast	$7.00
"SAR" VARIABLE O&M (mil/kWh):	June 2002 Official Forecast	1.61
CURRENT YEAR FUEL COST (mil/kWh):	June 2002 Official Forecast	27.94
BASE YEAR, O&M EXPENSES:	June 2002 Official Forecast	2002
ESCALATION RATE; "SAR" (%):	June 2002 Official Forecast	2.00%
ESCALATION RATE; SURPLUS (%):	June 2002 Official Forecast	4.80%
ESCALATION RATE; O&M (%):	June 2002 Official Forecast	2.50%
ESCALATION RATE; FUEL (%):	June 2002 Official Forecast	1.97%
ADJUSTABLE PORTION (mil/kWh):	Calculated	27.94
CAPITAL CARRYING CHARGE (%):	Financial Analysis - Or Order	13.260%
LEVEL CARRYING COST (mil/kWh):	Calculated	11.48
"TILTING" RATE (%):	Feb 2002 Official Forecast	2.50%
TYPE OF RATES:		FUELED
CURRENT YEAR:		2002

FUELED

SURPLUS COST (m/kWh)	
YEAR	VALUE
2002	33.54
2003	35.15
2004	36.83
2005	38.60
2006	40.45
2007	42.40
2008	N/A
2009	N/A
2010	N/A
2011	N/A
2012	N/A
2013	N/A
2014	N/A
2015	N/A
2016	N/A
2017	N/A
2018	N/A
2019	N/A
2020	N/A
2021	N/A
2022	N/A
2023	N/A
2024	N/A
2025	N/A
2026	N/A
2027	N/A
2028	N/A
2029	N/A
2030	N/A
2031	N/A
2032	N/A
2033	N/A
2034	N/A
2035	N/A
2036	N/A

ANNUAL CARRYING CHARGES Plant on-line in the year shown		
YEAR	CARRYING CHARGE	TILTED CAPITAL
2002	10.40	N/A
2003	10.61	N/A
2004	10.82	N/A
2005	11.03	N/A
2006	11.26	N/A
2007	11.48	N/A
2008	11.71	9.06
2009	11.94	9.29
2010	12.18	9.52
2011	12.43	9.76
2012	12.68	10.00
2013	12.93	10.25
2014	13.19	10.51
2015	13.45	10.77
2016	13.72	11.04
2017	13.99	11.31
2018	14.27	11.60
2019	14.56	11.89
2020	14.85	12.18
2021	15.15	12.49
2022	15.45	12.80
2023	15.76	13.12
2024	16.08	13.45
2025	16.40	13.78
2026	16.73	14.13
2027	17.06	14.48
2028	17.40	14.84
2029	17.75	15.22
2030	18.10	15.60
2031	18.47	15.99
2032	18.84	16.39
2033	19.21	16.80
2034	19.60	17.22
2035	19.99	17.65
2036	20.39	18.09

ANNUAL OPERATION & MAINTENANCE COSTS (m/kWh)				
YEAR	FIXED	VARIABLE	TOTAL	FUEL
2002	0.87	1.61	2.48	27.94
2003	0.89	1.65	2.54	28.49
2004	0.91	1.69	2.60	29.05
2005	0.94	1.73	2.67	29.62
2006	0.96	1.78	2.74	30.21
2007	0.98	1.82	2.80	30.80
2008	1.01	1.87	2.87	31.41
2009	1.03	1.91	2.95	32.03
2010	1.06	1.96	3.02	32.66
2011	1.08	2.01	3.10	33.30
2012	1.11	2.06	3.17	33.96
2013	1.14	2.11	3.25	34.63
2014	1.17	2.17	3.33	35.31
2015	1.20	2.22	3.42	36.01
2016	1.23	2.27	3.50	36.71
2017	1.26	2.33	3.59	37.44
2018	1.29	2.39	3.68	38.18
2019	1.32	2.45	3.77	38.93
2020	1.35	2.51	3.87	39.69
2021	1.39	2.57	3.96	40.48
2022	1.42	2.64	4.06	41.27
2023	1.46	2.70	4.16	42.09
2024	1.50	2.77	4.27	42.92
2025	1.53	2.84	4.37	43.76
2026	1.57	2.91	4.48	44.62
2027	1.61	2.98	4.60	45.50
2028	1.65	3.06	4.71	46.40
2029	1.69	3.14	4.83	47.31
2030	1.73	3.21	4.95	48.25
2031	1.78	3.29	5.07	49.20
2032	1.82	3.38	5.20	50.16
2033	1.87	3.46	5.33	51.15
2034	1.91	3.55	5.46	52.16
2035	1.96	3.64	5.60	53.19
2036	2.01	3.73	5.74	54.24

NON-ADJUSTABLE PORTION TOTAL COSTS (Surplus rates before 1st deficit year)					
YEAR	TILTED CAPITAL	TOTAL O&M	FUEL	SURPLUS	TOTAL
2002	N/A	N/A	N/A	33.54	33.54
2003	N/A	N/A	N/A	35.15	35.15
2004	N/A	N/A	N/A	36.83	36.83
2005	N/A	N/A	N/A	38.60	38.60
2006	N/A	N/A	N/A	40.45	40.45
2007	N/A	N/A	N/A	42.40	42.40
2008	9.06	2.87	0.00	N/A	11.93
2009	9.29	2.95	0.00	N/A	12.23
2010	9.52	3.02	0.00	N/A	12.54
2011	9.76	3.10	0.00	N/A	12.85
2012	10.00	3.17	0.00	N/A	13.17
2013	10.25	3.25	0.00	N/A	13.50
2014	10.51	3.33	0.00	N/A	13.84
2015	10.77	3.42	0.00	N/A	14.19
2016	11.04	3.50	0.00	N/A	14.54
2017	11.31	3.59	0.00	N/A	14.90
2018	11.60	3.68	0.00	N/A	15.28
2019	11.89	3.77	0.00	N/A	15.66
2020	12.18	3.87	0.00	N/A	16.05
2021	12.49	3.96	0.00	N/A	16.45
2022	12.80	4.06	0.00	N/A	16.86
2023	13.12	4.16	0.00	N/A	17.28
2024	13.45	4.27	0.00	N/A	17.72
2025	13.78	4.37	0.00	N/A	18.16
2026	14.13	4.48	0.00	N/A	18.61
2027	14.48	4.60	0.00	N/A	19.08
2028	14.84	4.71	0.00	N/A	19.55
2029	15.22	4.83	0.00	N/A	20.04
2030	15.60	4.95	0.00	N/A	20.54
2031	15.99	5.07	0.00	N/A	21.06
2032	16.39	5.20	0.00	N/A	21.58
2033	16.80	5.33	0.00	N/A	22.12
2034	17.22	5.46	0.00	N/A	22.68
2035	17.65	5.60	0.00	N/A	23.24
2036	18.09	5.74	0.00	N/A	23.83

FUELED

CONTRACT LENGTH (YEARS)	AVOIDED COST PRESENT VALUES (m/kWh) ON-LINE YEAR 2002	2003	2004	2005	2006	2007
1	32.18	33.72	35.34	37.04	38.82	40.68
2	31.05	32.54	34.10	35.74	37.45	10.54
3	29.95	31.39	32.90	34.48	9.71	9.95
4	28.90	30.29	31.74	8.93	9.16	9.39
5	27.89	29.22	8.23	8.43	8.64	8.86
6	26.90	7.57	7.76	7.96	8.16	8.36
7	6.97	7.15	7.32	7.51	7.70	7.89
8	6.58	6.74	6.91	7.09	7.26	7.44
9	6.21	6.36	6.52	6.69	6.85	7.02
10	5.86	6.01	6.16	6.31	6.47	6.63
11	5.53	5.67	5.81	5.95	6.10	6.26
12	5.22	5.35	5.48	5.62	5.76	5.90
13	4.92	5.05	5.17	5.30	5.43	5.57
14	4.65	4.76	4.88	5.00	5.13	5.26
15	4.38	4.49	4.61	4.72	4.84	4.96
16	4.14	4.24	4.35	4.46	4.57	4.68
17	3.90	4.00	4.10	4.20	4.31	4.42
18	3.68	3.78	3.87	3.97	4.07	4.17
19	3.48	3.56	3.65	3.74	3.84	3.93
20	3.28	3.36	3.45	3.53	3.62	3.71
21	3.10	3.17	3.25	3.33	3.42	3.50
22	2.92	2.99	3.07	3.15	3.22	3.31
23	2.76	2.83	2.90	2.97	3.04	3.12
24	2.60	2.67	2.73	2.80	2.87	2.94
25	2.45	2.52	2.58	2.64	2.71	2.78
26	2.32	2.37	2.43	2.49	2.56	2.62
27	2.19	2.24	2.30	2.35	2.41	2.47
28	2.06	2.11	2.17	2.22	2.28	2.33
29	1.95	2.00	2.05	2.10	2.15	2.20
30	1.84	1.88	1.93	1.98	2.03	2.08
31	1.73	1.78	1.82	1.87	1.91	0.00
32	1.64	1.68	1.72	1.76	0.00	0.00
33	1.54	1.58	1.62	0.00	0.00	0.00
34	1.46	1.49	0.00	0.00	0.00	0.00
35	1.37	0.00	0.00	0.00	0.00	0.00

CONTRACT LENGTH (YEARS)	SUMMED AVOIDED COST PRESENT VALUES (m/kWh) ON-LINE YEAR 2002	2003	2004	2005	2006	2007
1	32.18	33.72	35.34	37.04	38.82	40.68
2	63.23	66.26	69.44	72.77	76.27	51.22
3	93.18	97.65	102.34	107.25	85.97	61.17
4	122.08	127.94	134.08	116.19	95.13	70.56
5	149.97	157.16	142.31	124.62	103.77	79.41
6	176.87	164.74	150.07	132.58	111.93	87.77
7	183.84	171.88	157.40	140.08	119.62	95.66
8	190.42	178.63	164.31	147.17	126.89	103.11
9	196.63	184.99	170.83	153.85	133.74	110.13
10	202.49	191.00	176.99	160.16	140.21	116.76
11	208.02	196.66	182.79	166.12	146.31	123.01
12	213.24	202.01	188.28	171.74	152.07	128.92
13	218.16	207.06	193.45	177.04	157.50	134.49
14	222.80	211.82	198.33	182.04	162.63	139.74
15	227.19	216.31	202.94	186.76	167.47	144.70
16	231.33	220.55	207.28	191.22	172.03	149.38
17	235.23	224.56	211.38	195.42	176.34	153.80
18	238.91	228.33	215.25	199.39	180.41	157.97
19	242.39	231.89	218.91	203.13	184.25	161.90
20	245.67	235.26	222.35	206.66	187.87	165.61
21	248.77	238.43	225.61	210.00	191.29	169.12
22	251.69	241.42	228.67	213.14	194.51	172.42
23	254.44	244.25	231.57	216.11	197.55	175.54
24	257.04	246.92	234.30	218.91	200.42	178.48
25	259.50	249.43	236.88	221.56	203.13	181.26
26	261.82	251.81	239.32	224.05	205.69	183.88
27	264.00	254.05	241.61	226.41	208.10	186.35
28	266.06	256.16	243.78	228.63	210.38	188.69
29	268.01	258.16	245.83	230.72	212.53	190.89
30	269.85	260.04	247.76	232.70	214.56	192.97
31	271.58	261.82	249.58	234.57	216.47	192.97
32	273.22	263.49	251.29	236.33	216.47	192.97
33	274.76	265.08	252.92	236.33	216.47	192.97
34	276.22	266.57	252.92	236.33	216.47	192.97
35	277.59	266.57	252.92	236.33	216.47	192.97

FUELED

CONTRACT LENGTH (YEARS)	NON-ADJUSTABLE LEVELIZED AVOIDED COSTS (m/kWh) ON-LINE YEAR 2002	2003	2004	2005	2006	2007
1	33.54	35.15	36.83	38.60	40.45	42.40
2	34.31	35.96	37.68	39.49	41.39	27.79
3	35.08	36.77	38.53	40.38	32.37	23.03
4	35.86	37.58	39.38	34.12	27.94	20.72
5	36.63	38.39	34.76	30.44	25.35	19.40
6	37.40	34.84	31.74	28.04	23.67	18.56
7	34.60	32.35	29.62	26.37	22.52	18.01
8	32.55	30.53	28.08	25.15	21.69	17.62
9	30.98	29.15	26.92	24.24	21.07	17.35
10	29.77	28.08	26.02	23.55	20.61	17.17
11	28.81	27.23	25.31	23.00	20.26	17.03
12	28.03	26.55	24.75	22.57	19.99	16.94
13	27.39	26.00	24.29	22.23	19.78	16.89
14	26.87	25.55	23.92	21.96	19.61	16.85
15	26.44	25.17	23.62	21.73	19.49	16.84
16	26.08	24.86	23.37	21.56	19.39	16.84
17	25.78	24.61	23.16	21.41	19.32	16.85
18	25.52	24.39	22.99	21.30	19.27	16.87
19	25.31	24.21	22.86	21.21	19.24	16.90
20	25.13	24.06	22.74	21.14	19.22	16.94
21	24.97	23.94	22.65	21.08	19.20	16.98
22	24.85	23.83	22.57	21.04	19.20	17.02
23	24.74	23.75	22.51	21.01	19.21	17.07
24	24.65	23.68	22.47	20.99	19.22	17.11
25	24.57	23.62	22.43	20.98	19.24	17.16
26	24.51	23.57	22.40	20.97	19.26	17.21
27	24.46	23.54	22.38	20.98	19.28	17.26
28	24.42	23.51	22.37	20.98	19.31	17.32
29	24.38	23.49	22.37	20.99	19.34	17.37
30	24.36	23.47	22.36	21.00	19.37	17.42
31	24.34	23.46	22.37	21.02	19.40	17.29
32	24.32	23.46	22.37	21.04	19.27	17.18
33	24.31	23.46	22.38	20.91	19.16	17.08
34	24.31	23.46	22.26	20.80	19.05	16.98
35	24.30	23.34	22.14	20.69	18.95	16.90

CONTRACT LENGTH (YEARS)	ADJUSTABLE PLUS NON-ADJUSTABLE COSTS (m/kWh) ON-LINE YEAR 2002	2003	2004	2005	2006	2007
1	33.54	35.15	36.83	38.60	40.45	42.40
2	34.31	35.96	37.68	39.49	41.39	55.73
3	35.08	36.77	38.53	40.38	60.31	50.97
4	35.86	37.58	39.38	62.06	55.88	48.66
5	36.63	38.39	62.70	58.38	53.29	47.34
6	37.40	62.78	59.68	55.98	51.61	46.50
7	62.54	60.29	57.56	54.31	50.46	45.95
8	60.49	58.47	56.02	53.09	49.63	45.56
9	58.92	57.09	54.86	52.18	49.01	45.29
10	57.71	56.02	53.96	51.49	48.55	45.11
11	56.75	55.17	53.25	50.94	48.20	44.97
12	55.97	54.49	52.69	50.51	47.93	44.88
13	55.33	53.94	52.23	50.17	47.72	44.83
14	54.81	53.49	51.86	49.90	47.55	44.79
15	54.38	53.11	51.56	49.67	47.43	44.78
16	54.02	52.80	51.31	49.50	47.33	44.78
17	53.72	52.55	51.10	49.35	47.26	44.79
18	53.46	52.33	50.93	49.24	47.21	44.81
19	53.25	52.15	50.80	49.15	47.18	44.84
20	53.07	52.00	50.68	49.08	47.16	44.88
21	52.91	51.88	50.59	49.02	47.14	44.92
22	52.79	51.77	50.51	48.98	47.14	44.96
23	52.68	51.69	50.45	48.95	47.15	45.01
24	52.59	51.62	50.41	48.93	47.16	45.05
25	52.51	51.56	50.37	48.92	47.18	45.10
26	52.45	51.51	50.34	48.91	47.20	45.15
27	52.40	51.48	50.32	48.92	47.22	45.20
28	52.36	51.45	50.31	48.92	47.25	45.26
29	52.32	51.43	50.31	48.93	47.28	45.31
30	52.30	51.41	50.30	48.94	47.31	45.36
31	52.28	51.40	50.31	48.96	47.34	45.23
32	52.26	51.40	50.31	48.98	47.21	45.12
33	52.25	51.40	50.32	48.85	47.10	45.02
34	52.25	51.40	50.20	48.74	46.99	44.92
35	52.24	51.28	50.08	48.63	46.89	44.84

NON-LEVELIZED AVOIDED COST RATE (m/kWh) CONTRACT START YEAR	NON-ADJUSTABLE PLUS MOST RECENT ADJUSTABLE
2002	33.54
2003	35.15
2004	36.83
2005	38.60
2006	40.45
2007	42.40
2008	39.87
2009	40.17
2010	40.48
2011	40.79
2012	41.11
2013	41.44
2014	41.78
2015	42.13
2016	42.48
2017	42.84
2018	43.22
2019	43.60
2020	43.99
2021	44.39
2022	44.80
2023	45.22
2024	45.66
2025	46.10
2026	46.55
2027	47.02
2028	47.49
2029	47.98
2030	48.48
2031	49.00
2032	49.52
2033	50.06
2034	50.62
2035	51.18
2036	51.77

Case No. GNR-E-02-1
Exhibit 304
Witness: Mark T. Widmer

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer

July, 2002

AVOIDED COST CALCULATION MODEL
19-Jul-02
Non-Fueled

DATA TYPE	DATA SOURCE	PCP DATA
FIRST DEFICIT YEAR:	Long Run L&R	2008
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SURPLUS COST BASE YEAR:	June 2002 Official Forecast	2002
"SAR" PLANT LIFE (YEARS):	No Change	30
"SAR" PLANT COST ($/kW):	June 2002 Official Forecast	$632
BASE YEAR OF "SAR" COST:	June 2002 Official Forecast	2002
"SAR" CAPACITY FACTOR (%):	No Change	92%
UTLTY WT'D COST OF CAPITAL (%):	Oregon Order 01-787	8.620%
RATEPAYER DISCOUNT RATE (%):	Oregon Order 01-787	8.620%
"SAR" FIXED O&M ($/kW):	June 2002 Official Forecast	$7.00
"SAR" VARIABLE O&M (mil/kWh):	June 2002 Official Forecast	1.61
CURRENT YEAR FUEL COST (mil/kWh):	June 2002 Official Forecast	27.94
BASE YEAR, O&M EXPENSES:	June 2002 Official Forecast	2002
ESCALATION RATE; "SAR" (%):	June 2002 Official Forecast	2.00%
ESCALATION RATE; SURPLUS (%):	June 2002 Official Forecast	4.80%
ESCALATION RATE; O&M (%):	June 2002 Official Forecast	2.50%
ESCALATION RATE; FUEL (%):	June 2002 Official Forecast	1.97%
ADJUSTABLE PORTION (mil/kWh):	Calculated	0.00
CAPITAL CARRYING CHARGE (%):	Financial Analysis - Or Order	13.260%
LEVEL CARRYING COST (mil/kWh):	Calculated	11.48
"TILTING" RATE (%):	Feb 2002 Official Forecast	2.50%
TYPE OF RATES:		Non-Fueled
CURRENT YEAR:		2002

Non-Fueled

SURPLUS COST (m/kWh)	
YEAR	VALUE
2002	33.54
2003	35.15
2004	36.83
2005	38.60
2006	40.45
2007	42.40
2008	N/A
2009	N/A
2010	N/A
2011	N/A
2012	N/A
2013	N/A
2014	N/A
2015	N/A
2016	N/A
2017	N/A
2018	N/A
2019	N/A
2020	N/A
2021	N/A
2022	N/A
2023	N/A
2024	N/A
2025	N/A
2026	N/A
2027	N/A
2028	N/A
2029	N/A
2030	N/A
2031	N/A
2032	N/A
2033	N/A
2034	N/A
2035	N/A
2036	N/A

ANNUAL CARRYING CHARGES Plant on-line in the year shown		
YEAR	CARRYING CHARGE	TILTED CAPITAL
2002	10.40	N/A
2003	10.61	N/A
2004	10.82	N/A
2005	11.03	N/A
2006	11.26	N/A
2007	11.48	N/A
2008	11.71	9.06
2009	11.94	9.29
2010	12.18	9.52
2011	12.43	9.76
2012	12.68	10.00
2013	12.93	10.25
2014	13.19	10.51
2015	13.45	10.77
2016	13.72	11.04
2017	13.99	11.31
2018	14.27	11.60
2019	14.56	11.89
2020	14.85	12.18
2021	15.15	12.49
2022	15.45	12.80
2023	15.76	13.12
2024	16.08	13.45
2025	16.40	13.78
2026	16.73	14.13
2027	17.06	14.48
2028	17.40	14.84
2029	17.75	15.22
2030	18.10	15.60
2031	18.47	15.99
2032	18.84	16.39
2033	19.21	16.80
2034	19.60	17.22
2035	19.99	17.65
2036	20.39	18.09

ANNUAL OPERATION & MAINTENANCE COSTS (m/kwh)				
YEAR	FIXED	VARIABLE	TOTAL	FUEL
2002	0.87	1.61	2.48	27.94
2003	0.89	1.65	2.54	28.49
2004	0.91	1.69	2.60	29.05
2005	0.94	1.73	2.67	29.62
2006	0.96	1.78	2.74	30.21
2007	0.98	1.82	2.80	30.80
2008	1.01	1.87	2.87	31.41
2009	1.03	1.91	2.95	32.03
2010	1.06	1.96	3.02	32.66
2011	1.08	2.01	3.10	33.30
2012	1.11	2.06	3.17	33.96
2013	1.14	2.11	3.25	34.63
2014	1.17	2.17	3.33	35.31
2015	1.20	2.22	3.42	36.01
2016	1.23	2.27	3.50	36.71
2017	1.26	2.33	3.59	37.44
2018	1.29	2.39	3.68	38.18
2019	1.32	2.45	3.77	38.93
2020	1.35	2.51	3.87	39.69
2021	1.39	2.57	3.96	40.48
2022	1.42	2.64	4.06	41.27
2023	1.46	2.70	4.16	42.09
2024	1.50	2.77	4.27	42.92
2025	1.53	2.84	4.37	43.76
2026	1.57	2.91	4.48	44.62
2027	1.61	2.98	4.60	45.50
2028	1.65	3.06	4.71	46.40
2029	1.69	3.14	4.83	47.31
2030	1.73	3.21	4.95	48.25
2031	1.78	3.29	5.07	49.20
2032	1.82	3.38	5.20	50.16
2033	1.87	3.46	5.33	51.15
2034	1.91	3.55	5.46	52.16
2035	1.96	3.64	5.60	53.19
2036	2.01	3.73	5.74	54.24

NON-ADJUSTABLE PORTION TOTAL COSTS (Surplus rates before 1st deficit year)					
YEAR	TILTED CAPITAL	TOTAL O&M	FUEL	SURPLUS	TOTAL
2002	N/A	N/A	N/A	33.54	33.54
2003	N/A	N/A	N/A	35.15	35.15
2004	N/A	N/A	N/A	36.83	36.83
2005	N/A	N/A	N/A	38.60	38.60
2006	N/A	N/A	N/A	40.45	40.45
2007	N/A	N/A	N/A	42.40	42.40
2008	9.06	2.87	31.41	N/A	43.34
2009	9.29	2.95	32.03	N/A	44.26
2010	9.52	3.02	32.66	N/A	45.20
2011	9.76	3.10	33.30	N/A	46.15
2012	10.00	3.17	33.96	N/A	47.13
2013	10.25	3.25	34.63	N/A	48.13
2014	10.51	3.33	35.31	N/A	49.15
2015	10.77	3.42	36.01	N/A	50.19
2016	11.04	3.50	36.71	N/A	51.25
2017	11.31	3.59	37.44	N/A	52.34
2018	11.60	3.68	38.18	N/A	53.45
2019	11.89	3.77	38.93	N/A	54.59
2020	12.18	3.87	39.69	N/A	55.74
2021	12.49	3.96	40.48	N/A	56.93
2022	12.80	4.06	41.27	N/A	58.14
2023	13.12	4.16	42.09	N/A	59.37
2024	13.45	4.27	42.92	N/A	60.63
2025	13.78	4.37	43.76	N/A	61.92
2026	14.13	4.48	44.62	N/A	63.24
2027	14.48	4.60	45.50	N/A	64.58
2028	14.84	4.71	46.40	N/A	65.95
2029	15.22	4.83	47.31	N/A	67.36
2030	15.60	4.95	48.25	N/A	68.79
2031	15.99	5.07	49.20	N/A	70.25
2032	16.39	5.20	50.16	N/A	71.75
2033	16.80	5.33	51.15	N/A	73.28
2034	17.22	5.46	52.16	N/A	74.84
2035	17.65	5.60	53.19	N/A	76.43
2036	18.09	5.74	54.24	N/A	78.06

Non-Fueled

CONTRACT LENGTH (YEARS)	AVOIDED COST PRESENT VALUES (m/kWh) ON-LINE YEAR 2002	2003	2004	2005	2006	2007
1	32.18	33.72	35.34	37.04	38.82	40.68
2	31.05	32.54	34.10	35.74	37.45	38.29
3	29.95	31.39	32.90	34.48	35.25	35.99
4	28.90	30.29	31.74	32.45	33.14	33.84
5	27.89	29.22	29.88	30.51	31.15	31.81
6	26.90	27.51	28.09	28.68	29.29	29.91
7	25.32	25.86	26.41	26.96	27.54	28.12
8	23.81	24.31	24.82	25.35	25.89	26.44
9	22.38	22.85	23.34	23.83	24.34	24.85
10	21.04	21.49	21.94	22.41	22.88	23.37
11	19.78	20.20	20.63	21.07	21.51	21.97
12	18.60	18.99	19.39	19.80	20.22	20.65
13	17.48	17.85	18.23	18.62	19.01	19.42
14	16.44	16.79	17.14	17.51	17.88	18.26
15	15.45	15.78	16.12	16.46	16.81	17.16
16	14.53	14.84	15.15	15.47	15.80	16.14
17	13.66	13.95	14.25	14.55	14.86	15.17
18	12.84	13.12	13.39	13.68	13.97	14.27
19	12.07	12.33	12.59	12.86	13.13	13.41
20	11.35	11.59	11.84	12.09	12.35	12.61
21	10.67	10.90	11.13	11.37	11.61	11.86
22	10.03	10.25	10.47	10.69	10.92	11.15
23	9.43	9.64	9.84	10.05	10.26	10.48
24	8.87	9.06	9.25	9.45	9.65	9.85
25	8.34	8.52	8.70	8.88	9.07	9.27
26	7.84	8.01	8.18	8.35	8.53	8.71
27	7.37	7.53	7.69	7.85	8.02	8.19
28	6.93	7.08	7.23	7.38	7.54	7.70
29	6.52	6.66	6.80	6.94	7.09	7.24
30	6.13	6.26	6.39	6.53	6.67	6.81
31	5.76	5.88	6.01	6.14	6.27	0.00
32	5.42	5.53	5.65	5.77	0.00	0.00
33	5.09	5.20	5.31	0.00	0.00	0.00
34	4.79	4.89	0.00	0.00	0.00	0.00
35	4.50	0.00	0.00	0.00	0.00	0.00

CONTRACT LENGTH (YEARS)	SUMMED AVOIDED COST PRESENT VALUES (m/kWh) ON-LINE YEAR 2002	2003	2004	2005	2006	2007
1	32.18	33.72	35.34	37.04	38.82	40.68
2	63.23	66.26	69.44	72.77	76.27	78.97
3	93.18	97.65	102.34	107.25	111.52	114.96
4	122.08	127.94	134.08	139.70	144.65	148.80
5	149.97	157.16	163.96	170.21	175.81	180.61
6	176.87	184.67	192.05	198.89	205.10	210.52
7	202.19	210.53	218.45	225.86	232.63	238.64
8	226.00	234.84	243.28	251.21	258.52	265.08
9	248.38	257.69	266.62	275.04	282.86	289.93
10	269.42	279.18	288.56	297.45	305.74	313.30
11	289.20	299.38	309.19	318.51	327.25	335.27
12	307.80	318.37	328.58	338.32	347.48	355.92
13	325.28	336.23	346.81	356.94	366.49	375.34
14	341.72	353.01	363.95	374.44	384.37	393.59
15	357.18	368.79	380.07	390.90	401.18	410.76
16	371.71	383.63	395.22	406.38	416.98	426.90
17	385.37	397.58	409.47	420.92	431.83	442.07
18	398.21	410.70	422.86	434.60	445.80	456.33
19	410.28	423.03	435.45	447.46	458.94	469.75
20	421.63	434.62	447.29	459.55	471.28	482.36
21	432.31	445.52	458.43	470.92	482.89	494.21
22	442.34	455.77	468.89	481.61	493.81	505.36
23	451.78	465.40	478.73	491.66	504.07	515.84
24	460.65	474.46	487.98	501.11	513.72	525.70
25	468.99	482.98	496.68	509.99	522.79	534.96
26	476.83	490.99	504.86	518.34	531.32	543.67
27	484.20	498.52	512.55	526.20	539.34	551.87
28	491.13	505.60	519.78	533.58	546.89	559.57
29	497.65	512.25	526.58	540.52	553.98	566.81
30	503.78	518.51	532.97	547.05	560.64	573.62
31	509.54	524.40	538.98	553.19	566.91	573.62
32	514.96	529.93	544.63	558.96	566.91	573.62
33	520.05	535.13	549.94	558.96	566.91	573.62
34	524.84	540.02	549.94	558.96	566.91	573.62
35	529.35	540.02	549.94	558.96	566.91	573.62

Non-Fueled

CONTRACT LENGTH (YEARS)	NON-ADJUSTABLE LEVELIZED AVOIDED COSTS (m/kWh) ON-LINE YEAR 2002	2003	2004	2005	2006	2007
1	33.54	35.15	36.83	38.60	40.45	42.40
2	34.31	35.96	37.68	39.49	41.39	42.85
3	35.08	36.77	38.53	40.38	41.98	43.28
4	35.86	37.58	39.38	41.03	42.49	43.70
5	36.63	38.39	40.05	41.57	42.94	44.12
6	37.40	39.05	40.61	42.06	43.37	44.52
7	38.06	39.63	41.12	42.51	43.79	44.92
8	38.63	40.14	41.58	42.94	44.19	45.31
9	39.14	40.61	42.01	43.34	44.57	45.69
10	39.61	41.04	42.42	43.73	44.95	46.06
11	40.05	41.46	42.81	44.11	45.32	46.43
12	40.46	41.85	43.19	44.47	45.67	46.78
13	40.85	42.22	43.55	44.82	46.02	47.13
14	41.21	42.58	43.90	45.16	46.36	47.47
15	41.57	42.92	44.23	45.49	46.69	47.80
16	41.90	43.25	44.56	45.81	47.01	48.13
17	42.23	43.57	44.87	46.12	47.32	48.44
18	42.54	43.87	45.17	46.43	47.62	48.75
19	42.84	44.17	45.47	46.72	47.92	49.05
20	43.12	44.45	45.75	47.00	48.20	49.33
21	43.40	44.73	46.02	47.28	48.48	49.62
22	43.67	44.99	46.29	47.54	48.75	49.89
23	43.92	45.25	46.54	47.80	49.01	50.15
24	44.17	45.50	46.79	48.05	49.26	50.41
25	44.41	45.73	47.03	48.29	49.50	50.66
26	44.64	45.96	47.26	48.53	49.74	50.90
27	44.86	46.19	47.49	48.75	49.97	51.13
28	45.07	46.40	47.70	48.97	50.19	51.35
29	45.28	46.60	47.91	49.18	50.40	51.57
30	45.47	46.80	48.11	49.38	50.61	51.78
31	45.66	46.99	48.30	49.57	50.80	51.40
32	45.84	47.18	48.49	49.76	50.47	51.07
33	46.02	47.35	48.66	49.46	50.17	50.76
34	46.19	47.52	48.40	49.19	49.89	50.48
35	46.35	47.28	48.15	48.94	49.64	50.22

CONTRACT LENGTH (YEARS)	ADJUSTABLE PLUS NON-ADJUSTABLE COSTS (m/kWh) ON-LINE YEAR 2002	2003	2004	2005	2006	2007
1	33.54	35.15	36.83	38.60	40.45	42.40
2	34.31	35.96	37.68	39.49	41.39	42.85
3	35.08	36.77	38.53	40.38	41.98	43.28
4	35.86	37.58	39.38	41.03	42.49	43.70
5	36.63	38.39	40.05	41.57	42.94	44.12
6	37.40	39.05	40.61	42.06	43.37	44.52
7	38.06	39.63	41.12	42.51	43.79	44.92
8	38.63	40.14	41.58	42.94	44.19	45.31
9	39.14	40.61	42.01	43.34	44.57	45.69
10	39.61	41.04	42.42	43.73	44.95	46.06
11	40.05	41.46	42.81	44.11	45.32	46.43
12	40.46	41.85	43.19	44.47	45.67	46.78
13	40.85	42.22	43.55	44.82	46.02	47.13
14	41.21	42.58	43.90	45.16	46.36	47.47
15	41.57	42.92	44.23	45.49	46.69	47.80
16	41.90	43.25	44.56	45.81	47.01	48.13
17	42.23	43.57	44.87	46.12	47.32	48.44
18	42.54	43.87	45.17	46.43	47.62	48.75
19	42.84	44.17	45.47	46.72	47.92	49.05
20	43.12	44.45	45.75	47.00	48.20	49.33
21	43.40	44.73	46.02	47.28	48.48	49.62
22	43.67	44.99	46.29	47.54	48.75	49.89
23	43.92	45.25	46.54	47.80	49.01	50.15
24	44.17	45.50	46.79	48.05	49.26	50.41
25	44.41	45.73	47.03	48.29	49.50	50.66
26	44.64	45.96	47.26	48.53	49.74	50.90
27	44.86	46.19	47.49	48.75	49.97	51.13
28	45.07	46.40	47.70	48.97	50.19	51.35
29	45.28	46.60	47.91	49.18	50.40	51.57
30	45.47	46.80	48.11	49.38	50.61	51.78
31	45.66	46.99	48.30	49.57	50.80	51.40
32	45.84	47.18	48.49	49.76	50.47	51.07
33	46.02	47.35	48.66	49.46	50.17	50.76
34	46.19	47.52	48.40	49.19	49.89	50.48
35	46.35	47.28	48.15	48.94	49.64	50.22

NON-LEVELIZED AVOIDED COST RATE (m/kwh) CONTRACT START YEAR	NON-ADJUSTABLE PLUS MOST RECENT ADJUSTABLE
2002	33.54
2003	35.15
2004	36.83
2005	38.60
2006	40.45
2007	42.40
2008	43.34
2009	44.26
2010	45.20
2011	46.15
2012	47.13
2013	48.13
2014	49.15
2015	50.19
2016	51.25
2017	52.34
2018	53.45
2019	54.59
2020	55.74
2021	56.93
2022	58.14
2023	59.37
2024	60.63
2025	61.92
2026	63.24
2027	64.58
2028	65.95
2029	67.36
2030	68.79
2031	70.25
2032	71.75
2033	73.28
2034	74.84
2035	76.43
2036	78.06

CERTIFICATE OF SERVICE

I hereby certify that I served the foregoing Direct Testimony and Exhibits of Mark T. Widmer on behalf of PacifiCorp on the following named person(s) on the date indicated below by

- ☒ mailing with postage prepaid
- ☐ hand delivery
- ☐ facsimile transmission
- ☐ overnight delivery

to said person(s) a true copy thereof, contained in a sealed envelope, addressed to said person(s) at their last-known address(es) indicated below.

Scott Woodbury
Idaho PUC
472 W. Washington
Boise, ID 83702

Barton L. Kline
Monica Moen
Idaho Power Company
1221 W. Idaho Street
Boise, ID 83702

Robert J. Lafferty
Avista Corporation
PO Box 3727
Spokane, WA 99220

R. Blair Strong
Tom DeBoer
Paine Hamblen, et al
717 W. Sprague Avenue, Suite 1200
Spokane, WA 99201

Conley Ward
Givens Pursley LLP
PO Box 2720
Boise, ID 83701-2720

William J. Nicholson
Potlatch Corporation
244 California Street, Suite 610
San Francisco, CA 94111

Dean J. Miller
McDevitt & Miller LLP
420 W. Bannock Street
Boise, ID 83702

Peter J. Richardson
Richardson & O'Leary PLLC
PO Box 1849
Boise, ID 83616

Stuart Trippel
Trippel Mast Consulting
506 2nd Avenue, Suite 1001
Seattle, WA 98104-2328

Scott Pasley
David Hawk
J.R. Simplot Company
PO Box 27
Boise, ID 83707-0027

Ronald C. Barr
Earth Power Resources, Inc.
3203 S. Owasso Avenue
Tulsa, OK 74105

Owen H. Orndorff
Orndorff Law Offices
1087 W. River Street, Suite 230
Boise, ID 83702

Jane Gorsuch
Intermountain Forest Association
350 N. 9th Street, Suite 304E
Boise, ID 83702

Eric L. Olson
Racine, Olson, Nye, Budge & Bailey
PO Box 1391
Pocatello, ID 83204-1391

Rick S. Koebbe
WindWorks, Inc.
5356 N. Cattail Way
Boise, ID 83703

Anthony Yankel
29814 Lake Road
Bay Village, OH 44140

DATED: 22 July 2002.

Peggy Ryan